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Rewards and challenges of seismic monitoring for CO_2 storage: a fluid substitution study in the Gippsland basin, Victoria, Australia

Aline Gendrin[a]*, Norzita Mat Fiah[b], Francois Poupeau[c], Lawrence J. Pekot[a], Andrew Garnett[d]

[a]Schlumberger Carbon services, Paris, France, [b]LEAP Energy Australia Pty Ltd, Bribane, Australia, [c]Banque de france, Paris, France, [d]University of Queensland, Brisbane, Australia

Abstract

Seismic observation has key advantages that, in the right geological conditions, make it extremely valuable for CO_2 storage monitoring. Among surface techniques allowing the observation of the entire storage complex, it has by far the greatest vertical and lateral resolution and it can provide a full 3D view of the reservoir and overburden. However, in our experience, theoretical applicability of seismic acquisition for CO_2 plume tracking has often been challenged by the geology: high rock stiffness, heterogeneity, large depths, or low porosity in a storage site are not favorable factors. Moreover, there is uncertainty on the minimum levels of detectability. CO_2 might mix either homogeneously or create patches of variable saturation, and this can result in a large variability on the expected seismic signal, especially for saturations lower than 50%. We investigate the seismic signal expected for a location in the Gippsland Basin, Victoria, Australia. Using classical rock physics equations, CO_2 detectability at the reservoir level will present some challenges, but the possibility for detection above the reservoir is quite favorable. An understanding of the relative heterogeneity of storage formations is critical to establishing uncertainty and detection limits of time-lapse seismic technology.

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Keywords: Time-lapse seismic; CO2 monitoring.

* Corresponding author. Tel.: +33 1 7177 6411; fax: +33 1 7112 3131.
E-mail address: agendrin@slb.com.

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Introduction

Carbon dioxide (CO_2) monitoring is essential to manage the potential risks associated with geological storage. Two goals of monitoring include: (1) tracking the plume to locate the CO_2 within the injection formation, and to verify that subsurface movement behaves according to expectations; (2) checking containment to verify that all the CO_2 is within the target formation or locate any that may have migrated further (leakage). For these two goals, geophysical technologies have a key role to play. Most importantly, three dimensional (3D) surface seismic allows observation of the entire storage complex, with a vertical and lateral resolution (a few tens of meters) much higher than other technologies achieving a comparable coverage (Controlled Source Electro-Magnetic, gravity or Interferometric Synthetic Aperture Radar (InSAR)). Moreover, 3D surface seismic is a real 3D measurement. Gravity or InSAR surveys provide only a 2D image, from which 3D information needs to be inferred. Because of these advantages, 3D surface seismic is one of the strongest monitoring technology candidates to quantify the injected CO_2 [1, 2]. However, a major drawback of 3D surface seismic is its cost. Repetition of conventional 2D seismic surveys would keep many advantages of 3D seismic data, at a lower cost.

The sensitivity of seismic acquisition to acoustic impedance changes makes it highly sensitive in some ([1, 2]), but not all geological contexts. A number of feasibility studies have been carried out, where seismic detectability was challenging at the reservoir level. The reasons for this were diverse:

- CO_2 was planned to be injected in a residual gas cap with similar properties, and separate detectability of each could not be reached.
- CO_2 injection was too deep. A large depth is less favourable to seismic detectability.
- The porosity was too small.
- The reservoir was made of stiff rocks.

In all the above cases, and as expected, detectability conditions were easily reached at shallow depths in cases of possible leakage or upward migration scenarios. The 3D character of a seismic survey makes it highly valuable to cover all possible leakage pathways. However, it is important to assess uncertainty in leakage scenarios because CO_2 saturation descriptions might not be well constrained. In this case, the way CO_2 mixes with surrounding formation fluid (homogeneously or forming patches) might strongly impact the predicted answer and hence the value of the technology.

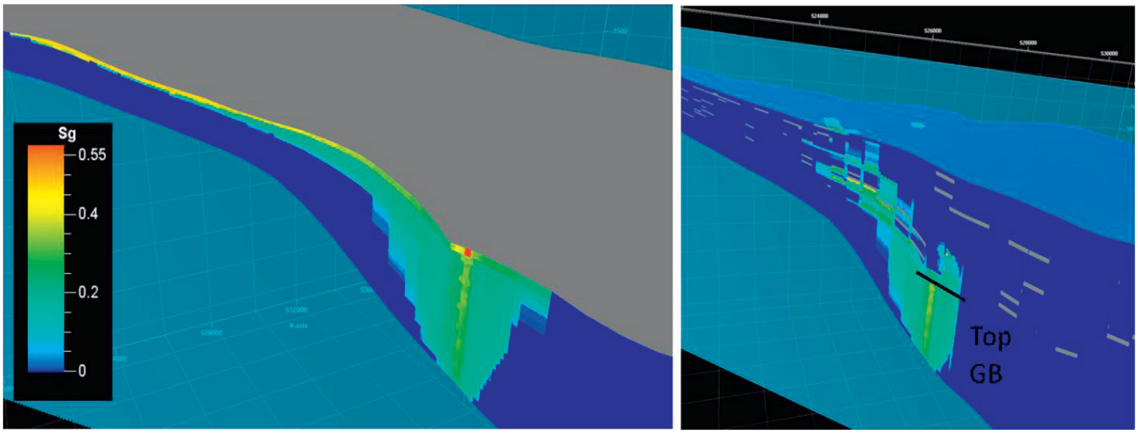

Figure 1: reservoir modelling results, 200 years after the end of injection, in the hypothesis of a horizontal/vertical permeability ratio equal to 0.1. On the left, the Halibut Subgroup was considered as a sealing formation. On the right, the Halibut Subgroup was considered as a non-sealing, low permeable formation.

Geological context

In a fluid substitution study in the western corner of Gippsland Basin, Victoria, Australia, the injection reservoir, the Golden Beach Subgroup, is located at a depth of 1725-2058 m depth. It is constituted of a mixture of sand, silt and clay. Sands have an effective porosity of 10-20%. The ultimate seal for the storage play was postulated to be the Lakes Entrance Formation, with additional sealing capacity postulated due to shales within the Halibut Subgroup. However, such individual shales might not be continuous everywhere, and so several cases were considered during the reservoir engineering study. The Halibut Subgroup was alternately considered as a sealing or non-sealing formation. Several scenarios were investigated with different vertical/horizontal permeability ratios. End members of modelled plume spread simulations are shown on Figure 1. With reference to that figure (Left) if the Halibut is continuous and sealing, some CO_2 will accumulate just below the seal; (Right) if the Halibut is not completely sealing, some CO_2 will migrate upward, but will stay underground, inside the storage complex, because of residual trapping [3] and the ultimate Lakes Entrance seal several hundred metres above. The overlying formations above the Halibut are made of siliclastic material, with a porosity varying between 0 and 40% and a volume of clay varying between 0 and 80%. A few thin coal layers in the overburden have a very low density. They attenuate seismic energy which is incident on the injection reservoir, however this should not affect time-lapse seismic, and we believe that they will not influence strongly the general conclusions presented in this paper, except, perhaps by decreasing effective signal to noise ratios. Figure 2 presents the logs used in this seismic response study, with corresponding formation tops.

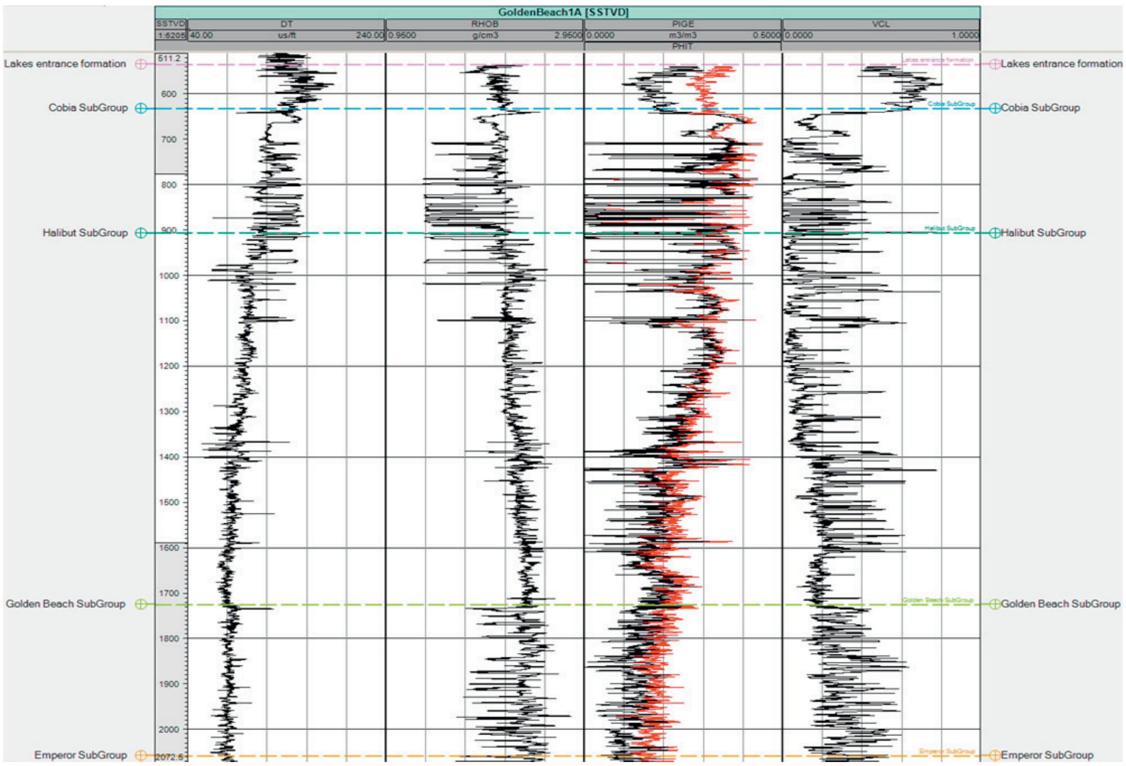

Figure 2: logs used in this study. From left to right: compressional slowness, density, porosity (total, in red, and effective, in black), volume of clay.

Methodology

Our scoping study has two main goals: (1) to determine whether seismic detectability might be reached inside the Golden Beach reservoir, which would allow plume tracking using seismic technologies; (2) to determine whether seismic detectability might be reached in case of migration above the Golden Beach (but still beneath the Lakes Entrance Formation). In order to provide relevant answers to these questions, we need to estimate what values of CO_2 saturation to expect in the reservoir, and above the reservoir, in case of upward migration. CO_2 saturations should be between a minimum value, the residual CO_2 saturation, and a maximum value, which is determined by the irreducible water saturation [4]. These two values could be measured in a range of representative samples in the laboratory, on cores, for each formation of interest. However, this data is rarely available at the scoping stage of CO_2 storage projects, and results provided in [4] are often used. Core data in the case of this scoping study were not available and results from [4] were used, considering that CO_2 saturation will be between 20 and 60%. In the reservoir, the CO_2 will accumulate below the caprock, and reach 60% saturation. In case of upward migration, the CO_2 should accumulate below the thin clay layers in the overburden, where it should also reach saturations between 30 and 60% depending on the existence of local structural traps and capillary entry pressures.

Based on existing pressure measurements and reservoir modelling, a temperature gradient of 3.1 C/100m, with a surface temperature of 14ºC, and a hydrostatic pressure gradient were assumed. A consistent salinity equal to 9000 ppm over the entire depth range was used for modelling. Using [5], the brine density, velocity, compressibility and viscosity were derived. To retrieve CO_2 properties, a specific equation of state [6] was used. Gassman’s equation [7] was used to calculate the results of our fluid substitution study.

Compressional velocity varies as a function of effective stress, as shown in [8]. In fluid substitution studies, the superposition of a fluid effect and a pressure effect is expected. We are directly interested in the fluid effect, because it reveals exactly where the CO_2 is located. The pressure effect will map the pressure change induced by CO_2 injection. But this effect is distributed over a pore volume much larger than the actual CO_2 plume. The effective pore pressure increase resulting from the injection will decrease the value of compressional velocity and this decrease, during injection, might be comparable in amplitude to the decrease induced by the injected fluid. The effect will be opposite after injection, where the pressure will equilibrate and trend back to hydrostatic pressure, thus increasing compressional velocity. Due to a lack of adequate input data to model this effect, no attempt was made to take into account the effect of pressure change on compressional velocity.

The fluid effect of injected CO_2 on the seismic signal will be twofold: (1) a compressional velocity change will result in a pull-down effect between time-lapse seismic surveys. A one to two milliseconds time-shift is necessary, in good circumstances, to achieve detectability, as shown in [9, 10]; (2) an acoustic impedance change will result in a seismic amplitude change. An acoustic impedance change larger than 5% is considered as a favourable factor for time-lapse seismic surveys [11]. This value was taken into account in an initial step, and subsequently refined in later results by taking into account time-lapse seismic noise.

Results

One large uncertainty in fluid substitution studies applied to CO_2 storage is due to the mixing law. Can we consider that CO_2 is mixed homogeneously with surrounding formation fluids or does it form patches (uneven areas with different saturations)? Each of these hypotheses corresponds to different frequency ranges, and the transition frequency between the two regimes can be calculated, and depends on CO_2 saturation, permeability, fluid bulk modulus, porosity, fluid viscosity and patch size [12]. The many variables, and the uncertainty on the patch size, make it impractical to decide whether homogeneous mixing or patchy saturation applies, and both results are considered possible. The difference between the two is used as an error bar. Figure 3 shows the expected acoustic impedance and compressional velocity changes obtained if 20, 40 or 60% of the mobile formation fluid is replaced by CO_2.

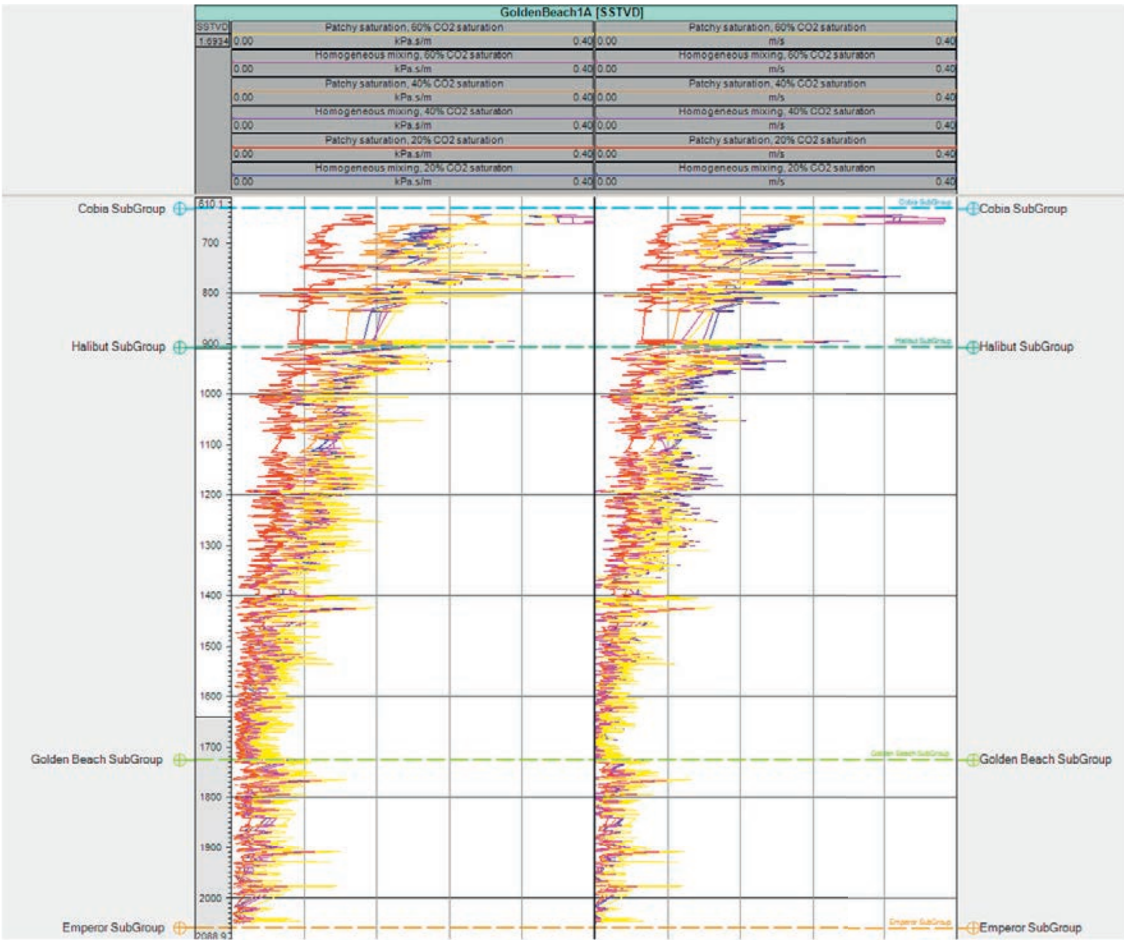

Figure 3: fluid substitution results for different mixing laws and different CO_2 saturations. The left column corresponds to the change in acoustic impedance. The right column is the change in compressional velocity. The different mixing law cases and applied CO_2 saturations are indicated in the legend.

The expected pull-down effect is shown on Figure 4. The magnitude of the pull-down effect is displayed as a function of the CO_2 layer thickness (plume thickness in the reservoir, or migrated CO_2 layer thickness above the initial reservoir). It is observed that detectability levels will be reached for a plume thicker than 150 m, inside the reservoir, even in the most pessimistic scenario (20% CO_2, with patchy saturation). This also means that any CO_2 accumulation of less than 100 m thickness at the reservoir level might not be visible in the seismic data, even in the most favourable hypothesis (60% CO_2, homogeneous mixing). In the case that CO_2 migrates above the initial reservoir, we consider a most unfavourable evaluation scenario: CO_2 saturations of 20% with a patchy saturation hypothesis. In Figure 4, it is observed that, as expected, it will be easier to detect upward migrating CO_2 if it accumulates at shallower depths. At 1600 m depth, a layer thicker than 100 m is necessary to reach detectability. At 1000 m depth, a layer of 20 m is enough. At 800 m depth, a layer of 10 m is sufficient.

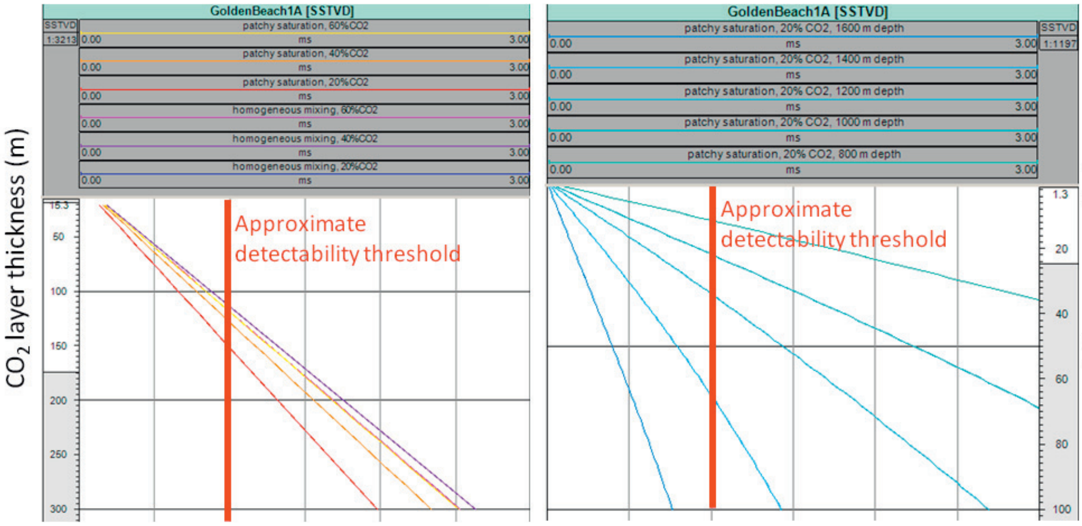

Figure 4: Left: magnitude of the pull-down effect expected below the reservoir after CO_2 injection, compared with an approximate detectability threshold. Right: magnitude of the pull-down effect expected in case of upward migration.

The change in acoustic impedance at the reservoir level is below 5%, in all cases, this is un-favourable circumstances for detectability [11]. As expected, in Figure 3, if homogeneous mixing applies, the acoustic impedance change is comparable for CO_2 saturations of 20, 40 and 60%. However, if patchy saturation applies, the signal obtained with 60% CO_2 saturation is stronger than the signal with 40 or 20% CO_2 saturation. Homogeneous mixing and patchy saturation give similar results for a saturation of 60%. In any case, the acoustic impedance change is lower than 5%, and this means that the lack of seismic amplitude variations will prevent plume tracking, our first objective. However, in case of upward migration, the acoustic impedance change in shallower formations will easily reach detectability, even in the most pessimistic hypothesis (patchy saturation, 20% CO_2). However, the second objective, leakage detection, is achievable. Because of the uncertainty on the appropriate mixing law to represent possible field conditions, there might also be uncertainty on the seismic signal level that will be observed.

The 5% threshold in acoustic impedance that is favourable for detectability is an approximate threshold that might be optimistic for a noisy onshore environment. An attempt is made to refine this threshold by introducing noise in the data, which corresponds to actual noise expected in the field. Time-lapse seismic noise is measured in terms of Normalized Root Mean Square (NRMS). Onshore, a NRMS level of 20-30% is commonly expected [13].

The very well-known tuning effect [14] is a constructive interference effect that occurs for thin layers. This results in stronger seismic amplitudes for thinner layers. In particular circumstances, this will result in peculiar observations in the seismic data: a thin CO_2 rich layer might appear bright in a seismic survey, and less bright in a later repeat survey while more CO_2 will have accumulated, forming a thicker layer. If we take an extreme case, a layer of CO_2 that has formed due to upward migration out of the injection reservoir below might be detectable in one survey, and below the noise level in the subsequent survey, even if the layer will be thicker. Figure 5 illustrates these statements. For this study, only CO_2 layer thicknesses large enough to avoid the tuning effect were considered. This is a conservative hypothesis, and the tuning effect might facilitate detectability, especially in case of leakage.

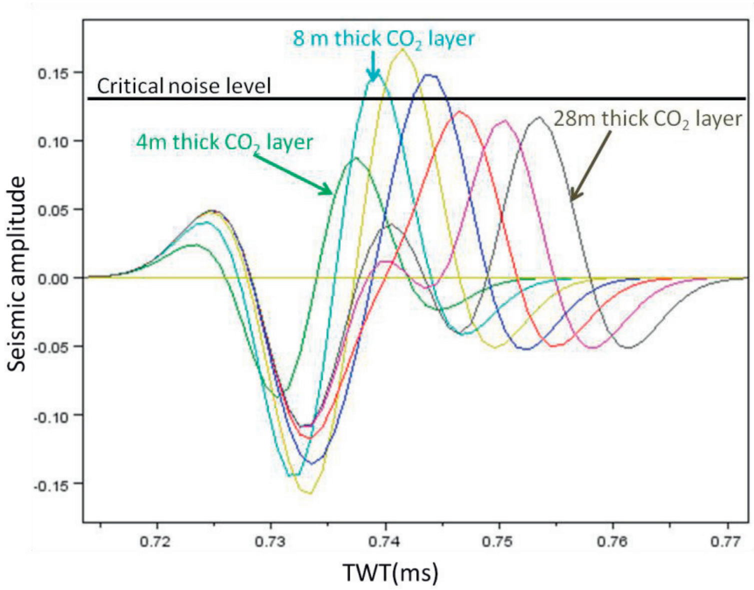

Figure 5: The tuning effect and its impact on CO_2 detectability. The seismic response for different CO_2 layer thicknesses is presented (thicknesses from 4 m to 28 m by step of 4 m), if we assume a central seismic frequency of 50 Hz. If the noise has the level indicated by the black horizontal line, seismic signal will be detectable with a CO_2 layer thickness of 12 m, but not with a layer of 20 m or more.

Figure 6 presents our results if we add noise with appropriate amplitude (30% NRMS) to our data. We consider the possibility of having CO_2 layers at different depths: 800, 1000, 1200, 1400, 1600, 1800 m depth. The 1800 m layer is inside the reservoir. Even in the more favourable hypothesis (CO_2 saturation equal to 60%), the signal corresponding to this layer is hidden by the noise. This confirms that seismic amplitude change will not enable CO_2 plume tracking. The other theoretical CO_2 layers, at 800, 1000, 1200, 1400 and 1600 m depth, are representative of five different migration scenarios. If CO_2 accumulates at 1600 m depth, the resulting amplitude change will not be detectable, even in the most optimistic hypothesis (60% CO_2 saturation). If CO_2 accumulates at 800 m depth, it will always be detectable even with a layer thickness as thin as ~10m (if the seismic central frequency is ~50 Hz). If CO_2 accumulates at 1000, 1200 or 1400 m depth, it will be detectable, except in the most pessimistic hypothesis (patchy saturation with CO_2 saturation of 20%).

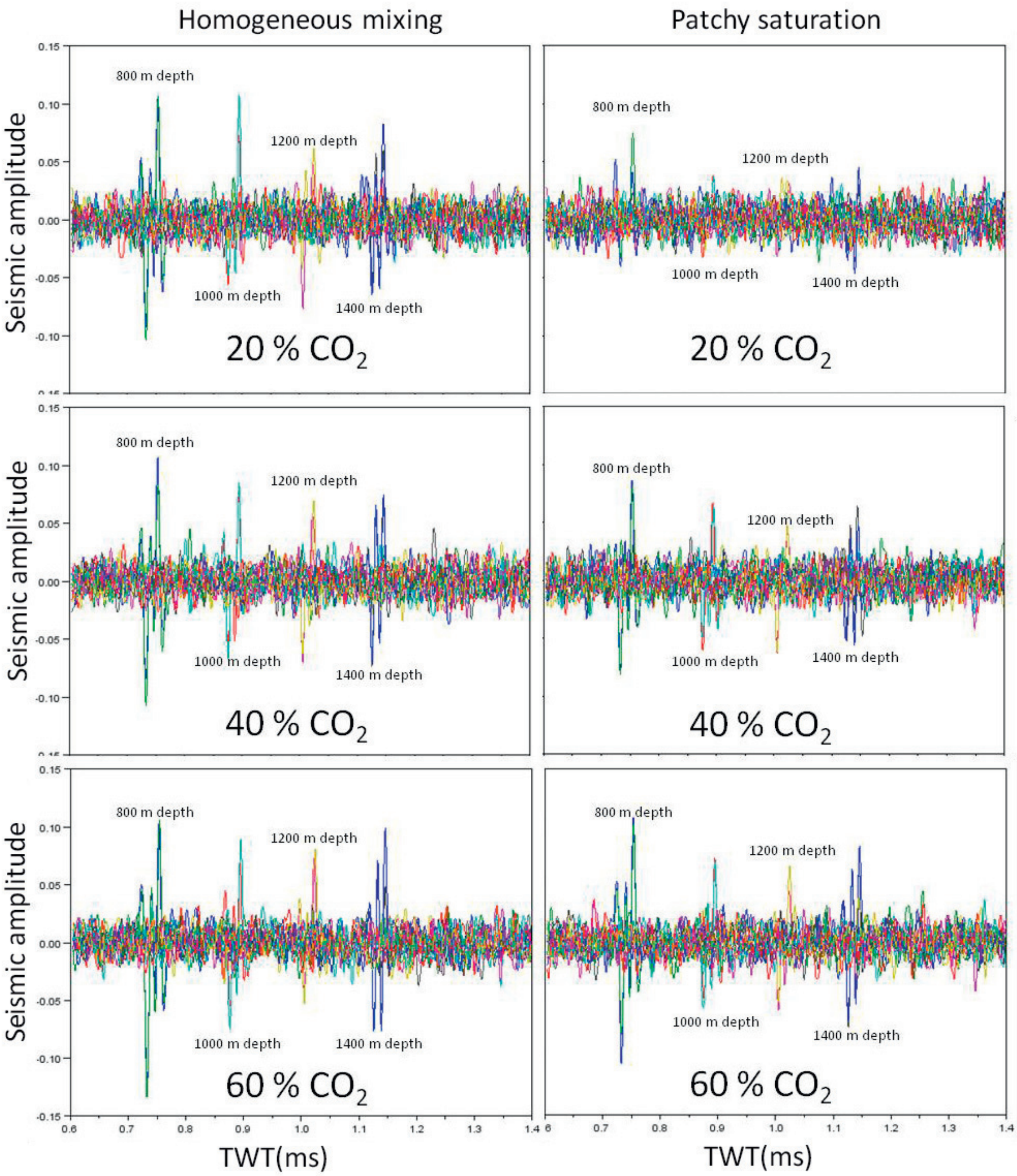

Figure 6: Six layers of CO_2 of 30 m thickness (above the tuning effect) are supposed to be present at 800, 1000, 1200, 1400, 1600, 1800 m depth. The central seismic frequency of the seismic data is supposed to be 50 Hz. As expected, the two deepest layers (1600 and 1800 m depth) are never above the detectability threshold. With patchy saturation, and a CO_2 saturation of 20%, only the layer at 800 m depth will be observable.

Conclusion

We have presented the results of a fluid substitution scoping study, in the Gippsland basin, Victoria, Australia. Based on our experience from more than a dozen similar fluid substitution studies in other geologic basins around the world, this case study is more representative of what will be observable by using seismic data in CO_2 storage than what is seen in a more ideal geological setting such as Sleipner [1].

The pull-down effect due to the injected CO_2 will be observable, inside and below the reservoir, when the CO_2 plume will have reached 150 m thickness or more. If upward migration occurs, the pull-down effect created by CO_2 will be observable if accumulation occurs above the reservoir and below the ultimate seal. Depending on the depth at which CO_2 accumulates, a layer thickness of 10 m (shallow) to more than 100 m (just above the reservoir) would likely be detectable in the most unfavourable assumptions (CO_2 saturations of 20%, with a patchy saturation mixing law).

Seismic amplitude variations are not likely to be detectable at the reservoir level. The signal will always be below seismic noise level (high, in this onshore environment). In case upward migration occurs, the location of the CO_2 can be mapped accurately, using the seismic amplitude change, in areas where CO_2 saturations are larger than 40%. If CO_2 saturations are below 40% and patchy saturation mixing law applies, the CO_2 will be below detectability levels, except at shallow depths (800 m). Considering time-lapse seismic amplitudes, layers of CO_2 thinner than 10m might be detectable, provided appropriate frequency content is obtained in the seismic (~50 Hz, central frequency, which is now a standard in present-day seismic acquisition). Because of the tuning effect, thin layers might be easier to detect than thicker layers.

Overall, seismic technology can have key advantages in the right setting. It covers the entire field in one observation. Among technologies allowing such a large spatial coverage, it has the highest spatial and vertical resolution. It is a real 3D technology (alternatively, if appropriate, repeat 2D surveys might also be shot). In case the location of some potential leakage paths is uncertain, 3D seismic technology may bring a decisive advantage. It is one of the strongest monitoring technology candidates for CO_2 quantification. Within limitations described in this paper, we believe that seismic data can be one of the most powerful and appropriate technologies to monitor a CO_2 storage site.

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